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Numerical investigation for Enhancing CO_2 Injectivity in Saline Aquifers

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Abstract

Even though the storage potential of saline aquifers is huge, the effective injection of large amounts of carbon dioxide into the reservoir is very challenging. Many saline aquifers have relatively low permeability which limits the injectivity of CO_2 to the aquifers. Injectivity is one of key factors for determining the feasibility for storage of CO_2 in a brine field. It is determined by many factors, such as injection pressure, the length of the injection well screen, porosity and permeability of target formations. In this paper, numerical simulation studies of CO_2 injection into brine-saturated reservoirs have been conducted to investigate approaches for enhancing CO_2 injectivity by modifying the injected fluid properties, using longer injection screen, selecting different injection depth, and introducing hydraulic fracturing and acidizing for storage aquifer improvement. The studies conclude that the CO_2 injectivity can be improved through appropriate approaches.

Keywords: Saline aquifers; Injectivity; Hydraulic fracturing; Sanility

1. Introduction

Among geological formations for carbon dioxide storage, deep saline aquifer is considered as the most promising reservoir due to its huge potential and common occurrence when compared to oil and gas reservoirs. Even though the storage potential of saline aquifers is huge, the effective injection of large amount to the reservoir is very challenging. Injectivity is a very important variable for CO_2 geological sequestration in a brine aquifer. Injection rate increases with increase of injection pressure. For economic reasons, people tend to inject CO_2 at the largest possible rates with lowest cost by using smallest number of wells and simplest wells. Thus a typical CO_2 injection well is likely to run at the largest bottomhole pressure that is safe.

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Injectivity is determined by many factors, such as the length of injection well screen (or thickness of storage formation), porosity and permeability of target formations. However, it does not always exist of ideal (thick high permeable) aquifers near stationary CO_2 emission sources. To increase the injection rates, people may consider using more injection wells, adopting horizontal wells, or improving aquifer conditions through hydraulic fracturing. All these approaches are costly or technically challenging. A constant-pressure well exhibits a varying rate of CO_2 injection for following reasons: (1) multiphase flow effects, (2) capillary effects due to CO_2-water replacement near the wellbore, (3) change of permeability due to precipitation of dissolved salts. Mobility of supercritical CO_2 and mixture with brine in the formation determine the variation of injectivity. Modifying fluid properties or change injection operating condition may also help in improving the injectivity. The two-phase behaviour of CO_2 and brine mixture under the conditions equivalent to geological storage is very complicated. A full understand of the flow phase behaviour will help in improvement of injectivity.

A very limited number of studies for injectivity of CO_2 storage in saline aquifers have been carried out. Burton et al.[1] developed analytical expressions for the injectivity variation in terms of phase mobilities and the speeds of saturation fronts. They found a four-fold variation in injectivity when seven different CO_2/brine relative permeability curves are used, holding all other reservoir parameters the same. Jikich et al. [2] showed that, for a fixed CO_2 injection pressure, the attainable CO_2 injection rate increases with horizontal well length. Okwen et al. [3] investigated the effect of well orientation (vertical vs. horizontal) and well length on the injection of CO_2 in deep saline aquifers through numerical models. They concluded that horizontal wells may be preferable if the goal is to sequester a large amount of CO_2 in a short period of time, but do not offer a significant advantage in terms of long-term capacity of a potential repository.

In this paper, numerical modeling studies for carbon dioxide injection into brine-saturated reservoirs have been conducted to investigate effectiveness of approaches for enhancing CO_2 injectivity by modifying the injected fluid properties, using horizontal well with different length, selecting different injection depth, and introducing hydraulic fracturing and acidizing for storage aquifer improvement. Hypothetical CO_2 injection models were developed by incorporating detailed well design for the studies. The general parallel multiphase flow simulator TOUGH2-MP[4],[5] is selected for the reservoir simulations.

2. Theoretical Investigation

Large scale injection of CO_2 into a saline aquifer will induce a variety of coupled physical and chemical processes, including multiphase fluid flow, fluid pressurization and geomechanical effect, solute transport, and chemical reactions between fluids and formation minerals. These processes may cause variation of injection rates. Variation of capillary pressure and fluid viscosity during the multiphase flow process will lead to fluid mobility change. Continue injection of CO_2 into an aquifer will produce an increase in pore pressure, which, in turn will alter the effective stress state leading to permeability and porosity variations. In addition, solute transport will enhance chemical reaction between CO_2 and the formation minerals, and the chemical reaction processes will lead to the precipitation of solid minerals. This results in a porosity decrease with an associated potential for significant decrease in permeability[6]. Permeability is one of the key factors that determine the injectivity of a storage formation. Its change will definitely lead to the change of injectivity.

Movement of water-NaCl-CO_2 mixtures in the storage formation follows the multiphase extension of Darcy's law[7]. The phase fluxes F_β are given by:

$$F_\beta = -\rho_\beta \frac{kk_{r\beta}}{\mu_\beta}(\nabla P_\beta - \rho_\beta g) \tag{1}$$

where k is the intrinsic permeability, ρ_β is the density of phase β, $k_{r\beta}$ is the relative permeability of phase β, μ_β is the flux viscosity of phase β and g is the gravitational acceleration.

To achieve highest injection rate, a maximum safe-pressure needs to be selected for the injection. Once the injection pressure is fixed, the injection rate is determined by fluid density, intrinsic permeability, and mobility ($k_{r\beta}/\mu_\beta$). Intrinsic permeability k is the property of a formation, which may only be altered through costly mechanical or chemical processes. It is also possible to enhance the injectivity by altering the injected fluid properties, such as reduction of its density or increase of its mobility (by reducing viscosity or increasing relative permeability). Viscosity is a measure of the resistance of a fluid which is being deformed by either shear stress or tensile stress. Under disposal conditions (supercritical CO_2) the viscosity of carbon dioxide can be less than the viscosity of the aqueous phase by a factor of 15. Fluid density and mobility are functions of temperature and pressure. Through changes of injected fluid temperature or/and injection pressure, the injectivity may change in the same formation conditions.

3. Model Studies

3.1 Conceptual model

Hypothetical CO_2 injections are adopted for this study. The injection processes are simulated with a simplified three-dimensional (3D) numerical model. The 3D model covers an area of 10km×10km. The injection well is located in the center of the model domain. The storage formation into which CO_2 is injected, located at a depth of approximately 1000 m below the ground surface, is 45 m thick and bounded at the top by a sealing layer 20 m thick. Figure 1 shows the schematic diagram of 2-D XZ cross-section of the model domain. Two three-dimensional unstructured meshes for different injection schemes were designed as shown in a plan view in Figure 2 for the model domain discretization.

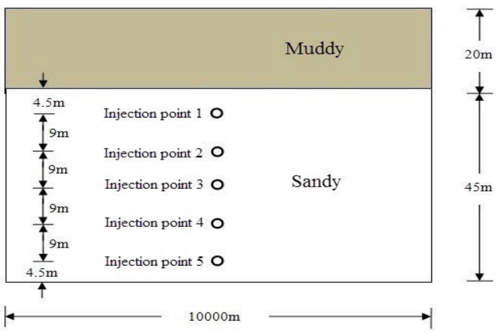

Fig.1 2-D XZ cross-section view of the 3D model for base case

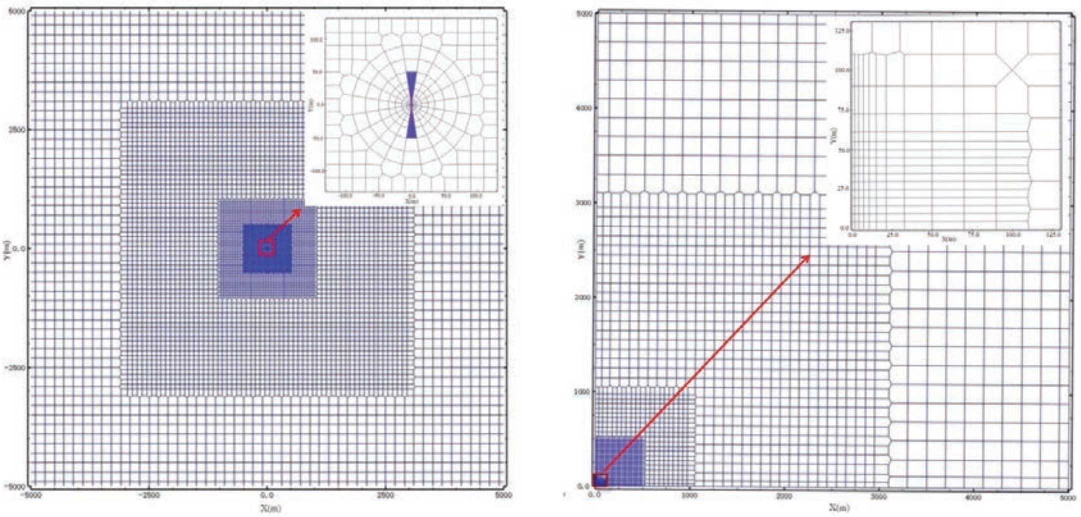

Fig.2 Plane view of the 3D mesh (a) Mesh for cases of vertical well and a 100m length hydraulic fracturing zone (Red line: fracturing zone； Blue area: influence zone), (b) cases with horizontal well

3.2 Model parameters and investigation cases

Carbon dioxide is injected through a borehole with a constant-pressure for 20 years. The simulation runs cover a time period of 20 years. Except the cases for investigation of temperature influence on the injectivity, it is assumed that the temperature within the storage aquifer does not change with time and the system is considered isothermal. For the isothermal simulations, temperature is also needed to calculate the fluid properties, such as density and viscosity. The initial temperature varies linearly with depth, assuming a geothermal gradient of 2.5 ^{0}C per 100m depth and the temperature of 15^{0}C at the land surface. Initial pressure distribution in the simulation domain follows hydrostatic equilibrium. Vertical hydraulic communication at the top and bottom of the domain with outside formations is weak. Both top and bottom boundaries are considered as impermeable boundary. The lateral boundaries of the system are open. The injection pressure is about 1.4 times the hydrostatic pressure.

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The parameters used for this study are given in Table 1. The storage formation is low permeability sandstone, which is assumed to be non-deformable and initially saturated with brine. The permeability of the formation is homogeneous, but may vary due to salt precipitation or dissolution during CO_2 injection. In all cases, both aquifer and aquitard formations have been assigned the same set of properties without variation in depth. The vertical/horizontal ratio of permeability is assumed to be 1/10 in all the layers. Van Genuchten model is used to calculate the capillary pressure and relative permeability of the two-phase flow of CO_2 and water.

Different simulation cases are designed to investigate the influence of fluid properties on the CO_2 injectivity. The base case investigates CO_2 injectivity under the assumed conditions as shown in Table 1 with injection at the depth 1020～1065m. Results of other cases will compare with those from base case. Hydraulic fracturing and acidizing for storage aquifer improvement is taken into account in case 2a and case 2b (see Table 2). Case 3a reduces the formation water salinity to 2.0%, while case 3b and case 3c increases the salinity to 3.8 and 20%, respectively. The purpose of these cases is to examine the influence of salinity on the injection rate. In the case 3d, prior to injection of CO_2, we firstly inject pure water into the formation over 10 days. This case will show the effect of low salinity surrounding the wellbore on the CO_2 injection rate. Different lengths of horizontal wells are introduced in case 4a~ case 4c (with length of 60, 100, and 120m for the three cases, respectively). The perforating position on injection well is adjusted in case 5a (1020～1047m) and 5b (1038～1065m). In case 6a ~ case 6e, the temperature of the injected CO2 is explored. It is expected that the injected CO_2 temperature will influence injectivity. Case 6a ~ case 6e are non-isothermal simulations, which take into account the system temperature changes over time. The injected CO_2 temperature for the cases: 6a-the same as formation temperature, 6b-5 ^{0}C lower than initial formation temperature, 6c -5 ^{0}C higher than initial formation temperature, 6d-10 ^{0}C higher than initial formation temperature, and 6e-18 ^{0}C higher than initial formation temperature.

Supercritical carbon dioxide is injected with constant pressures for all cases. The injection pressures are determined based on hydrostatics pressure at the injection point. Constant pressure injection will help in analysis of the influence of single parameter on the injection rate.

Table 1 Hydrogeological and thermodynamical properties used in the base-case simulation

Properties		Values for aquifer	Values for aquitard
Permeability/mD	horizontal	20	8.00E-06
	vertical	2	8.00E-07
Porosity		0.08	0.008
Rock density/(kg·m^{-3})		2600	2600
Heat conductivity/(W·m^{-1}·℃$^{-1}$)		2.51	2.51
Rock grain specific heat/(J·kg^{-1}·℃$^{-1}$)		920	920
Pore compressibility/Pa^{-1}		6.00E-10	6.00E-10
Salinity X_{NaCl}/ %		3	3
Residual water saturation S_{lr}		0.4	0.4
Residual CO_2 saturation		0.18	0.18
Parameter λ		0.4	0.4

Table 2 Sensitivity scenarios for hydraulic fracturing cases

Case name	Properties		Fracture zone	Affected fracture zone
Case 2a	Permeability/mD	Horizontal	2000	200
		Vertical	200	20
	Porosity		0.2	0.2
Case 2b	Permeability/mD	Horizontal	20000	2000
		Vertical	2000	200
	Porosity		0.2	0.2

4. Result and Discussion

4.1 Impact of hydraulic fracturing on injectivity

As shown in Figure 3, different degrees of hydraulic fracturing cases show different injection rates during the injection period. The aquifer reservoir keeps in relative unstable state after injecting CO_2 for a short time, and injection rate fluctuates greatly. The main physical mechanisms may be the displacement of brine away from the injection well by injected immiscible CO_2 fluid, which lead to sharp increase in reservoir pressure. After a while, CO_2 migrates away from the wellbore and gradually dissolves to water. It is obvious that the injection rate increases a lot through hydraulic fracturing in early stage. The injection rate of case 2b is larger than that of case 2a and base-case, which indicates that injection rate increases with a greater degree of fracturing. Hydraulic fracturing contributes to the increasing of porosity and the absolute permeability, also the contact area between reservoir and the injection well. All of these effects lead to a larger flux of CO_2. Simulation results also indicate that in long term the effect of hydraulic fracturing on injectivity is quite limited.

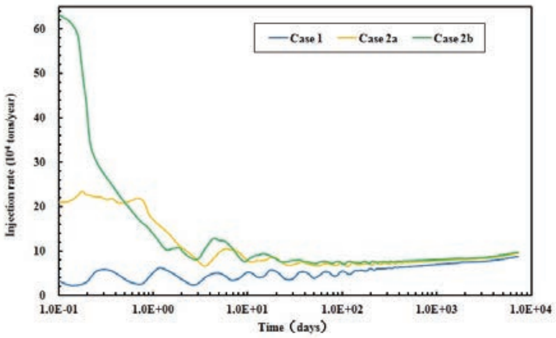


Fig.3 Evolution of total injection rate for hydraulic fracturing cases, 2a: K_f=2D; 2b: K_f=20D

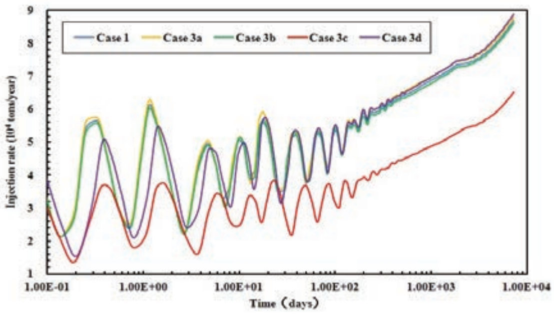


Fig.4 Evolution of total injection rate for different salinity cases, 3a: 2%, 3b: 3.8%, 3c: 20%, 3d: injects freshwater first

4.2 Impact of salinity on injectivity

Impact of salinity on injectivity was investigated through simulation cases with different salinity. Figure 4 shows the simulation results of the injection rates at different time. Constant pressure injection produces variable rates due to change of mobility during injection. The injection rates of case 3a and case 3d are slightly higher than base-case, while the results of case 3b and case 3c are opposite. This indicates that a higher injection rate can be reached for lower salinity aquifers with the same injection conditions. Fresh water injection for short period will help reduce the formation water salinity around the injection well. CO_2 injection in high salinity aquifer may cause precipitation of solid salt near the wellbore which will lead to reduce of the aquifer porous space and further reduce its porosity and permeability. The effects of water pre-infusion method are not obvious in this simulation. Water pre-infusion method would be much more effective for higher salinity aquifer (e.g. 20%).

4.3 Impact of length of horizontal well on injectivity

Evolution of total injection rate for different lengths of horizontal well cases is shown in Figure5. Compared to the injection rate of base case 1, injection rate of case 4b and 4c is higher, while that of case 4a is lower, for the reason of different lengths of horizontal well. It is noted that injection rate of case 4c with longer well screen is much higher than case 4a. After injection for 20 years, injection rate of case 4c with a horizontal well of length L=120m, increases about 4-14%. By Comparing three horizontal well cases, we can find that injection rate could improve about 3000 tons/year with the length of horizontal well increasing 20 meters. It can be concluded that the longer the horizontal wells, the better improvement for injectivity. In comparison to vertical injection well, the length of horizontal well is not limited by the thickness of the reservoir. For reservoir with certain thickness, horizontal well can effectively increase the contact area between the wellbore and reservoir to improve the injection rate. Based on the results, it appears that a horizontal well of longer length offers significant benefit over a vertical well in short period.

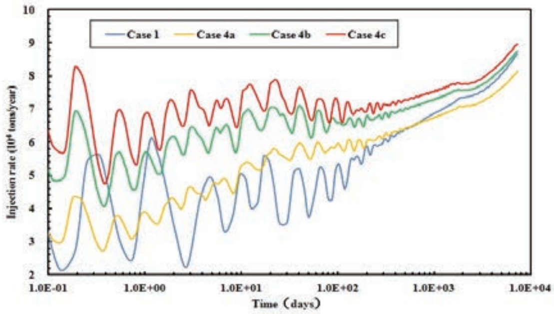


Fig.5 Evolution of total injection rate for different lengths of horizontal well cases: 4a: 60m, 4b: 100m, 4c: 120m

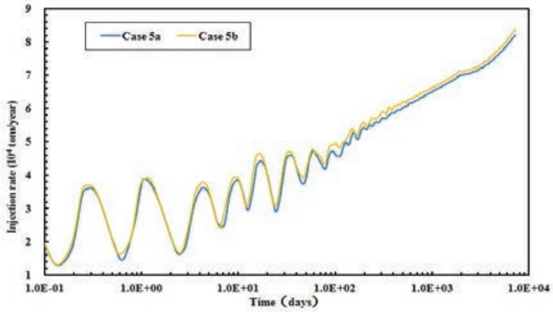


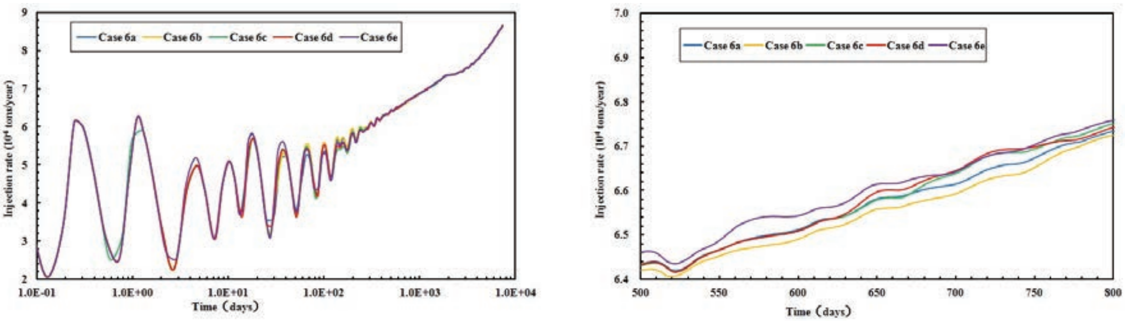
Fig.6 Evolution of injection rate for different perforating perforating location, 5a: 1020-1047m, 5b: 1038-1965m

4.4 Impact of perforating position on injectivity

Figure 6 shows the results of the injection rates for cases with different perforating positions. It is noted that injecting CO_2 in deeper aquifer is slightly better than in shallower aquifer. Injecting CO_2 in deeper aquifer could take full advantage of the reservoir space for the reason that CO_2 tends to move upwards to the upper aquifer driven by buoyant. Based on the results, it appears that well screens located at the lower part of the reservoir can effectively improve the injectivity for a relatively thicker reservoir.

4.5 Impact of temperature of injected fluid on injectivity

From Figure 7, we can see that at most time, the injection rates of case 6c, case 6d and case 6e are higher than that of case 6a, while the injection rate of case6b with colder temperature is lower than that of case 6a. In addition, the injection rate of Case 6d is higher than the injection rates for case 6c and case 6e in most of the time. This indicates that injection rate does not keep increasing with the higher temperature. Once the temperature of injected fluid increases to a critical point, injection rate will reach a maximum, then decrease with higher temperature. From the value of calculated increment, it is clear that impact of temperature of injected fluid on injectivity is not significant.



(a) For the whole simulation period (b) From 500d～800d

Fig.7 Evolution of total injection rate for cases with different temperature of injected fluid

5. Conclusions

In this paper, the influence of injected fluid properties, well length; injection location, and hydraulic fracturing on injectivity has been investigated through numerical models. The conclusions are summarized as following:

(1) If economically permitted, the approaches such as using horizontal well or longer injection screen, reducing the salinity of the reservoir by extending the period of injecting water for higher salinity aquifer and introducing hydraulic fracturing of sufficient degree for storage aquifer improvement can help to increase the CO_2 injectivity.

(2) For a relatively thicker formation, injection screen located at the deep part of the formation may help in improving the injectivity.

(3) Horizontal well may be preferable if the goal is to sequester a large amount of CO_2 in a short period of time, but do not offer a significant advantage in terms of long-term injectivity of a potential repository.

(4) Changing the temperature of the injected fluid has very limited impact on the injection rate and accumulative injection mass.

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